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Waterflood Management: A Case Study of the Northwest Fault Block Area of Prudhoe Bay, Alaska, Using Streamline Simulation and Traditional Waterflood Analysis

G. H. Grinestaff, BP-Amoco   Daniel J. Caffrey, BP-Amoco

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Abstract

This case study of a complex multiple-Zone waterflood in Prudhoe Bay, Alaska, focuses on the basics of waterflood management that are often overlooked. Evaluation of injection well conformance, flood front behavior, and reservoir description, followed by improved injection well management resulted in dramatic improvements in waterflood performance.

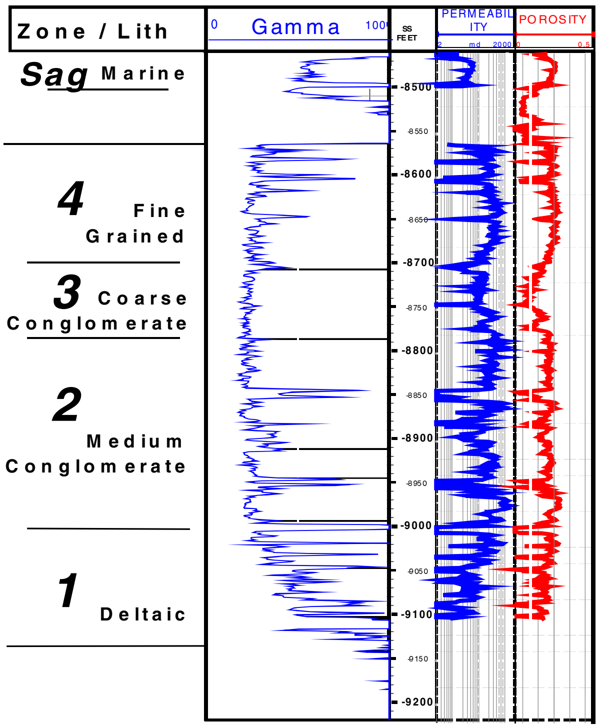
Assurance of waterflood performance requires an integrated approach and accurate performance predictions. The performance of the Northwest Fault Block (NWFB) waterflood was analyzed with traditional decline curves, Hall plots, and a thorough review of well histories to ascertain that it was under performing. A high-resolution 3-D streamline model proved to be the simulation of choice to answer regional and individual well performance questions for this complex waterflood. After achieving a history match for each of the 200+ wells, streamline modeling provided accurate results of vertical and area wide sweep inefficiencies that were later verified by horizontal drilling. Water cycling was quantified by streamline simulation and injection reduced by 30-40%, resulting in increased production and cost savings. Expansion of the waterflood into the gravity drainage area was stopped. Most importantly, bypassed oil is being developed through an aggressive injection well replacement program.

These promising results were achieved by a multidisciplinary team that focused on understanding micro and macro scale reservoir mechanisms. This holistic understanding of mature waterflood behavior, was achieved with a thorough understanding of injection well behavior and streamline simulation at a detailed scale to match each wells performance.

Introduction

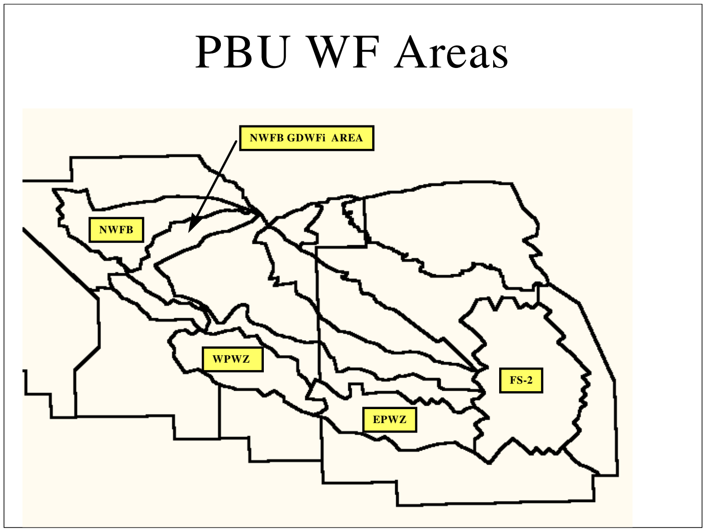
Prudhoe Bay, located on the North Slope of Alaska, is the largest oil field in North America. The field produces from the Permo-Triassic Ivishak formation, primarily made up of braided river deposits of sandstone and conglomerate. The reservoir has traditionally been divided up into four main Zones based on lithologic characteristics (Figure1). Reservoir properties including shale frequency, differ between the Zones and across the field due to deposition and diagenesis.

Figure 1: Prudhoe Bay Type Log of Lithology



The field was found with up to 500 feet of saturated 27 degree API oil underlying a large gas cap. The down-dip peripheral areas of the field, where no gas cap existed, are produced using the waterflood and miscible gas injection process (Figure 2). The main area of the field is produced by gravity drainage with large scale gas cap cycling for vaporization of oil and condensate in the original and expanded gas cap.

Figure 2: Prudhoe Bay Waterflood Areas



Field History

The Northwest Fault Block (NWFB) Area is the northwest portion of the main field area of the Prudhoe Bay Unit, see Figures 2 & 3. This structurally complex area of the field is bound by faults on three sides with the Eastern edge (the Gravity Drainage Waterflood Interaction Area or "GDWFI") sharing the large gas cap where gravity drainage exists. The NWFB originally contained 1.75 Billion Barrels of oil. Permeability varies significantly through the vertical section from 10 to 2000 md.

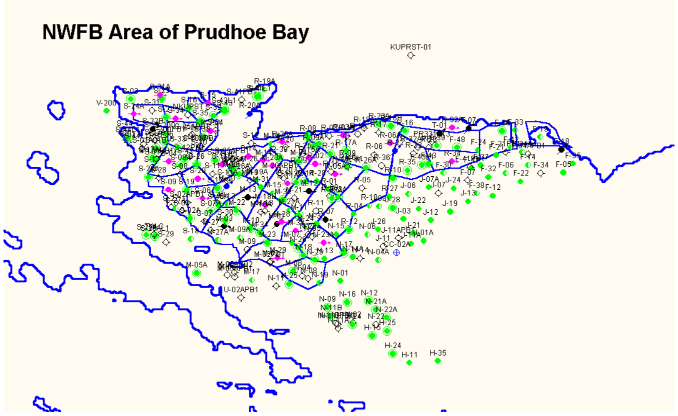
The NWFB was produced under primary recovery (solution gas drive, gravity drainage with gas cap expansion, and a relatively small water drive) from 1977 until August 1984 when 18 patterns were converted into a nominal 320 acre inverted nine spot waterflood. In 1987 a Water Alternating Gas(WAG) process was initiated using a enriched hydrocarbon gas as a miscible injectant. The waterflood area has had pattern size reductions and pattern reconfiguration changes into a line drive by conversions and infill drilling. It has also been expanded by extension drilling into the periphery. The GDWFi area has experienced infill development to a nominal 80 acre well spacing. The NWFB now contains 36 injection wells and is now a mature waterflood with substantial remaining enhanced oil recovery (EOR) potential. Zones 2 and 3 have been essentially water swept. Zone 4 is the primary target for the flood today with the majority of the unswept oil in the Zone 4B interval (upper half of Zone 4).

Statement of the Problem

Performance of the Northwest Fault Block Waterflood

In early 1996 an analysis was undertaken to ascertain why the NWFB area was underperforming compared to forecasts of the area. Performance predictions, using decline curve analysis, indicated that the recovery (40%-45%) would fall short of the expected 55%. Comparisons with other in-field analog areas like the Eastern Peripheral Wedge Zone (EPWZ) confirmed its under-performance.

Figure 3: Map of NWFB Area and Patterns

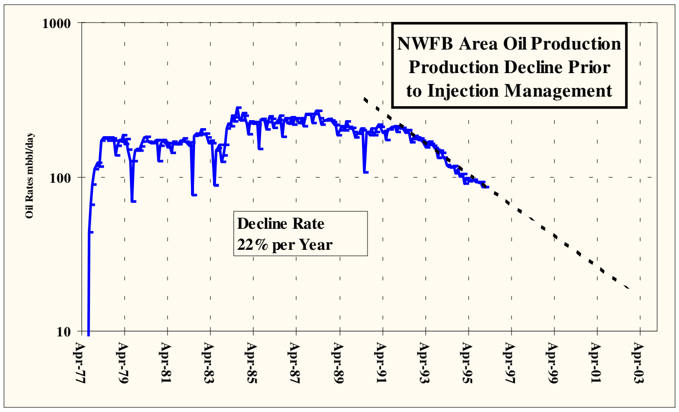


Integrated Analysis to Address the Problem

Decline Analysis

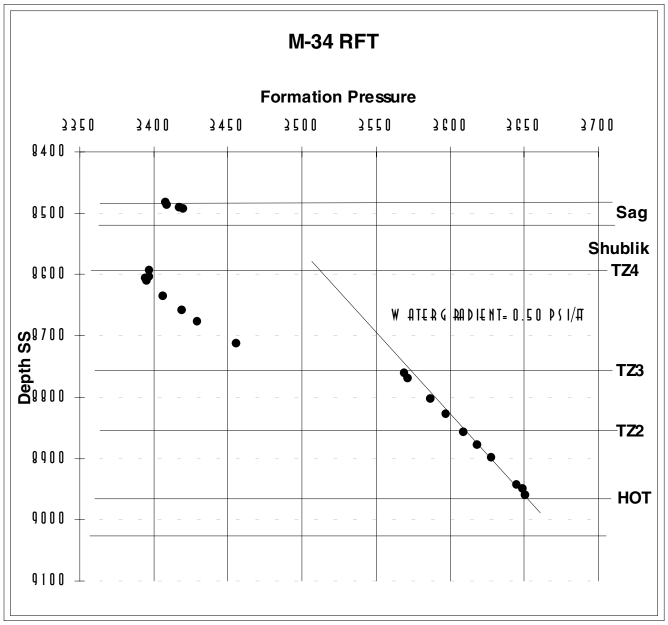
The analysis of performance began with an examination of field performance using decline analysis. Decline curves showed a very steep decline following the hydraulic fracture program which occurred in 1991 and 1992 (Figure 4).

Figure 4: NWFB Oil Rate and Decline



Repeat Formation Testing (RFT) completed in 1994 on several wells showed that Zone 4 pressures were systematically lower than Zone 3 pressures indicating much lower vertical permeability than earlier conceived. Well M-34 (Figure 5) shows this pressure change of over 100 psi between Zone 4 and Zone 3.

Figure 5: M-34 RFT taken 3Q 1994



RFT results prompted a re-look of the entire geologic description of the area. Subsequent core description analysis and holistic regional stratigraphy completed in May 1997, indicated that Zone 4 was a series of fine and coarse grain sands. "The coarse grained system uniformly has good reservoir quality whilst the fine grained system comprises mud-rich deposits and poor quality sandstones with an order of magnitude lower permeabilities. Lacustrine mudrocks induce the characteristic gamma spikes which punctuate the flat gamma response of Zone 4." (Ref. 1, Badley, Ashton & Associates Ltd). This system of sand on sand packages with occasional lacustrine mudstones are in effect a highly layered system with limited vertical hydraulic communication in the upper part of Zone 4.

Injection Well Diagnosis

The waterflood strategy of the NWFB was to inject water to match the allocated reservoir voidage of the predefined local pattern area. This is the traditional method used throughout the Prudhoe Bay Unit. Since the NWFB area was considered a single flood unit no attempts were made to allocate production and injection on a vertical basis.

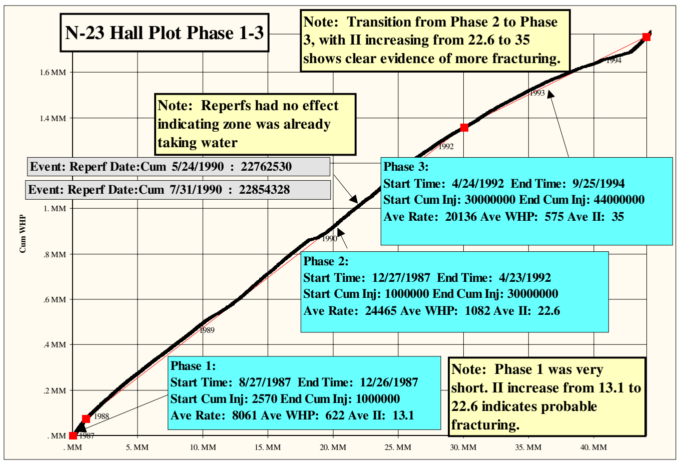
Flow meters or spinners were used to estimate the vertical injection distribution by Zone. Unfortunately, flow meters only indicate near wellbore flow, which can be very misleading (Ref. 2 SPE, Production Engineering Monograph).

Thermoelastic fracturing has long been understood as a phenomena in and around injection wells. Prudhoe Bay injection wells have been shown to fracture at pressures significantly below the initial formation stress. This finding led to the industry's first major study of thermal fracturing by Perkins and Gonzalez (Ref. 3) They showed that cooling of the 200° F reservoir by seawater at 80° F will cause a thermoeleasic stress reduction of more than 1000 psi (Ref. 4)

The NWFB injection began with clean 80° F seawater, then changed to 160° F produced water with small amounts of oil and solids. The extent of thermoelastic fracturing in the NWFB was not fully appreciated until a more holistic injection analysis was undertaken. Injection well analysis began with a thorough understanding of each wells history including drilling, perforating and stimulations. Most injection wells were converted from production so this included the time period when the wells were producing. The next step included constructing a Hall Plot (Ref. 5) for each injection well (Figure 6). Injection phases were determined for each Hall Plot. A phase was determined from slope changes in the straight line or linear portions of the Hall Plot. Then the Hall Plot was annotated with well history information. Finally a theoretical calculation was completed to estimate the injection rate of each perforated interval using the radial Darcy flow equation. Permeability was taken from a poro-perm relationship of Prudhoe Bay wells.

By completing this type of analysis it became obvious that flowmeters by themselves were misleading at best. A much better analysis came from the holistic approach outlined. Most wells analyzed indicated much higher perm-height than was open in the well bore. This was interpreted as a fracture system which had developed from Zone 4 perforations down into Zone 2 and 3. Since the permeability of Zones 2 and 3 are much higher, the flow was ultimately distributed by the permeability profile of the rocks penetrated by the fracture system.

Figure 6: Hall Plot Analysis and Historical Events



Given this method of allocating injection, it was estimated that over two thirds of the injection wells in the NWFB region were injecting predominantly into Zone 3, a very mature water swept interval.

Streamline Flood Front Tracking Simulation

Well Performance Expectations

After completing the decline, RFT, and injection well analysis a 3-D streamline front tracking simulation model was developed to integrate the understandings into one prediction. By comparing streamline simulation results to well behavior and surveillance data, future expectations for each well can be viewed with more confidence.

Fit for Purpose Simulation

Due to the highly complex nature of the waterflood areas in Prudhoe Bay, engineers have had difficulty in predicting fluid movements. To accurately resolve structure, geology, and fluids, models sizes start at 300,000 cells with 200-300 wells, covering 23 years of production history. High resolution faulted models are key to predicting fluid movements in the NWFB.

The choices available to forecast reservoir performance in the area were generally classified into two categories. Numerical simulation and analytical. Analytical approaches such as Dykstra Parsons, Stiles and material balance techniques fail to discriminate communication between layers in the reservoir. Numerical simulation techniques were then examined to select the most appropriate tool.

Finite difference techniques have long been the norm for the industry and particularly Prudhoe Bay. Full field models with sophisticated wellbore hydraulic routines and surface network packages have been used extensively for large scale problem solving. In more recent times, grid refinement techniques have been employed within the large full field simulator to examine a smaller portion of the field. Full field models and partial field models have been developed for the Prudhoe Bay Field and the NWFB Area. Although these methods can provide meaningful results, they are slow, cumbersome, and have not provided a detailed prediction for each well to help manage the waterflood at the well level. Streamline simulation techniques have grown from simple 2 dimensional, 2 phase methods without gravity to today's versions which are 3 dimensional and account for gravity. Streamline simulators have traditionally been very successful in tracking fluid movement in the reservoir. Since this was one of the primary goals in the analysis, streamline simulation was investigated further.

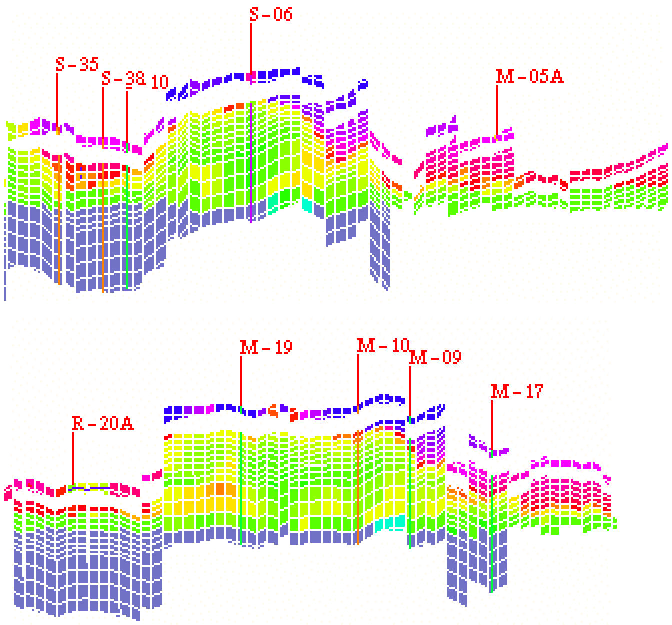
Frontsim, a streamline based front tracking method, has become the simulation of choice for the NWFB since it addressed the most relevant issues in the area. Development and application of complex 3D models using Frontsim started in Alaska in 1996. Full scale 3-D models in Prudhoe Bay are now being developed and history matched in only a few months instead of years with the same size finite difference simulator. This allows engineers to focus on understanding reservoir and well behavior and not simply simulator development The streamlines directly quantify volumes between injectors and producers to provide a 3-D dynamic prediction of injection support.

Successful Streamline Simulation in the NWFB

The streamline model is being used for forecasting, drilling, well work, understanding injection well conformance, and dynamic allocations to manage the waterflood. Several development drilling locations have now been successfully drilled as per model predictions, additionally water shut-offs have been implemented. New information is input and the entire simulation rerun in 1-2 hours. This allows decisions to be made on a daily basis, an impossibility for conventional simulation.

Model cross sections in Figure 7, show the structural and fluid complexity being resolved. Each model cell is 400' x 400' and approximately 20' - 30' thick. Water saturation at each time step shows flood fronts advancing from water injection and aquifer influx. Production from each well in the simulation is being matched, and flood fronts match open hole logs as development drilling continues.

Figure 7: Model Complexity and Flood Front Movements



Well by Well Production History Match over 23 years

Frontsim is providing a detailed NWFB history match of oil and water production over the entire 23 year history of Prudhoe Bay, for each well. Reservoir voidage is input, oil and water rates and saturation are predicted. Because of the maturity of water movements in the NWFB, detail for each producing well in the history match provides for an accurate means to quantify volumes from aquifer and injection.

Key parameters of the history match were vertical permeability and injection well conformance. An iterative process of matching flood fronts, initial breakthrough, and water cut behavior was undertaken. Because of waterflood maturity, small changes in these key parameters made large effects in the producers, indicating a relatively unique solution.

Several iterations were made each day and a timely solution reached.

The history match process was accomplished in stages. The first stage was to match early water breakthrough response from the aquifer before waterflood start. This was critical to obtain the proper distribution of aquifer influx. Previous material balance work had indicated that about 40,000 bwpd was entering the NWFB Area from the aquifer. The aquifer source was located where the Heavy Oil Tar(HOT) occurred in Zone 3 conglomerates. The finely gridded model provided detail in locating the HOT intersection with Zone 3. By adjusting the relative volumes in each region a good match was obtained.

The next stage involved regional flood front behavior. A first pass at injection well conformance and permeability of the open frame work conglomerates(within Zone 3) helped to match flood fronts.

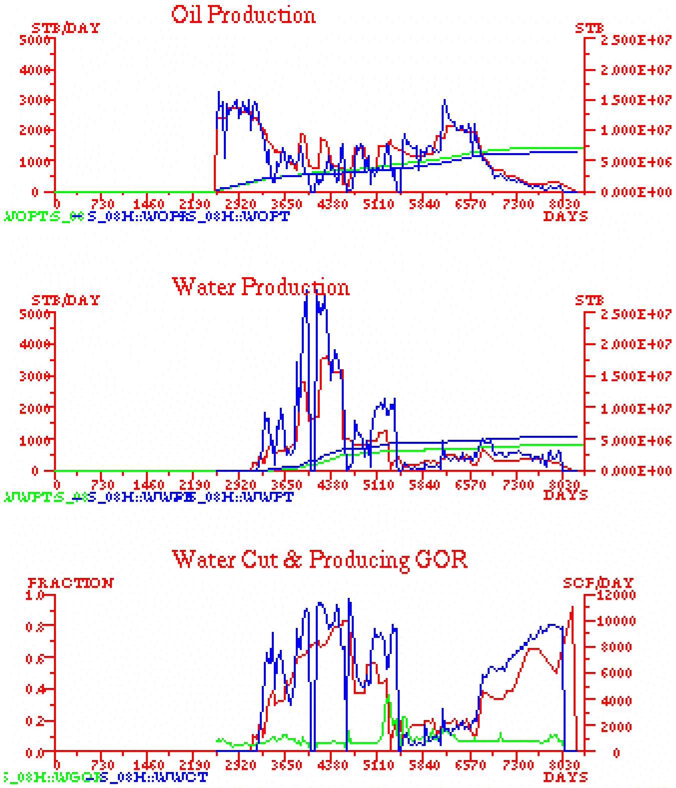
The next stage examined early water breakthrough timing and watercut response in close wells. This was accomplished by adjusting injection conformance and vertical permeability. All permeability adjustments were on a layer basis over the entire area.

Finally, adjustments were made to well completions.. These adjustments accounted for thermoelastic fracture growth out of Zone 4 and into Zone 3 and 2 for the injectors, and hydraulic prop-fraced in the producers. Usually this was accomplished by opening layers below the perforated interval. This adjustment provided virtually the 90% solution and the most dominant portion of the history match process. Each of these history match phases required an integrated understanding of the geology, wells, and displacement process.

Figure 8 shows Well S-08 history matched rates and cumulative production for oil and water predictions. Historical GOR is presented for mechanistic review only(it was not a history match parameter). Reservoir voidage and injection are input. Output is oil and water rates along with saturation for flood fronts for each time step. This is a typical match for each well in the model. Notice the large variations in watercut resulting from well work and stimulation. This type of detail is extremely difficult to match without accurate detail of flood front progression in three dimensions.

Streamline simulation provides a detailed history match of oil and water production over the entire 23 year history of Prudhoe Bay, for each well. Because injection conformance is uncertain, due to near wellbore effects in the NWFB, model history match results confirmed injection well analysis that indicated near wellbore effects were dominating injection well conformance.

Figure 8: Production history match Well S-08



Solution to the Problem

Management of Injection Wells

Understanding the vertical conformance of injected fluids was the key to solving the under performing NWFB waterflood. This single point can not be over emphasized.

Re-drilling Injection Wells

From March of 1997 to the present 16 injection wells have been re-drilled in the NWFB region. These wells have confirmed the injection well analysis with open hole logs indicating 25 to 75 feet of oil column remaining in locations just 500 feet away from the original injection well. The well design utilized by these wells varied with the structure and stratigraphy expected, but generally high angle wells were utilized. This well type was used to place injection into the unswept upper Zone 4 at high rates and at several injection points along the well bore in hopes to contain the fracture system and thereby increase vertical sweep conformance.

Setting Injection Targets with Dynamic Allocations

The history matched Frontsim model provided a means to quantify the amount of production that could be supported by injection. Because the NWFB shares pore volume with the gravity drainage area, waterflood injection and production can receive flux from the gas cap area. Figure 9 streamlines show the ten year old fully developed NWFB waterflood. Static pattern allocations are being used to set injection volumes. Injected fluids are fluxing to producers several patterns away, and large amounts of fluids are actually leaving the planned water flood area. Although unit voidage replacement is being attempted, gas cap flux is coming into the waterflood and water flux is exiting the area.

Figure 9: Static Allocations 1995 NWFB Prudhoe Bay

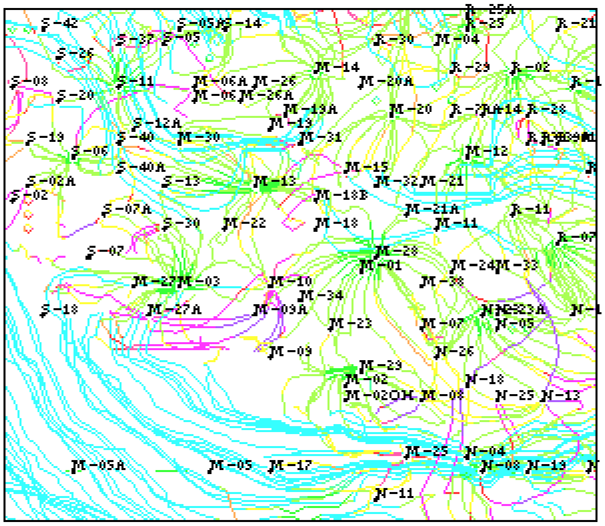
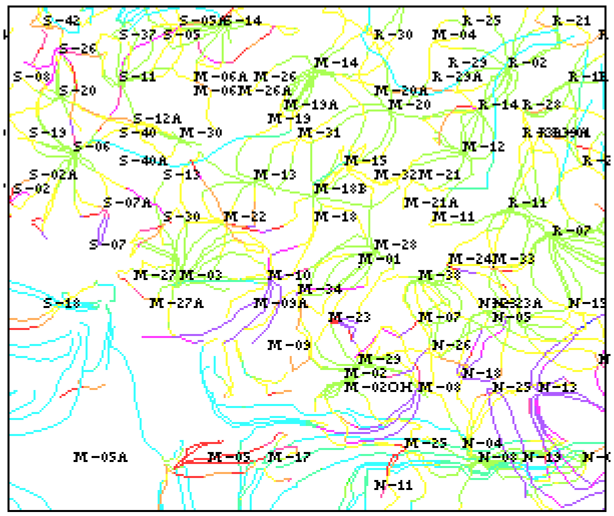


Figure 10 shows streamlines over the same waterflood area after injection well re-drills and injection allocation using Frontsim was implemented. Injection at this point has been reduced by 40%. Flux out of the water flood area has been eliminated, and flux between patterns (pattern skew) is minimal. Flux from the gas cap is also starting to be mitigated from re-drilling injection wells to increase support in upper Zone 4.

Figure 10: Dynamic Allocations 1998 NWFB Prudhoe Bay

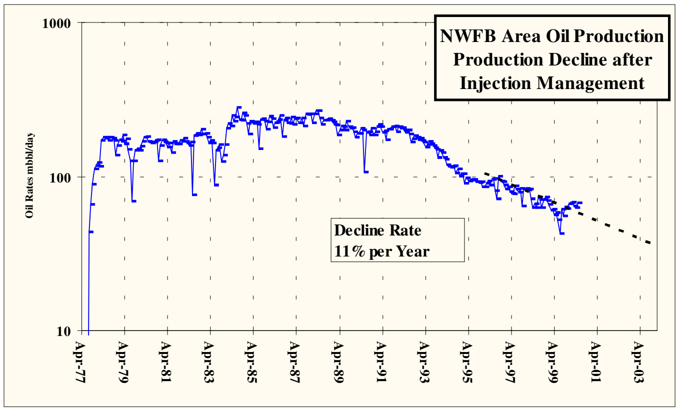


Results

Integrated Injection Well Management

The NWFB decline has been cut in half (22% to 11%, Figure 4 vs. Figure 11) after integrated injection well management.

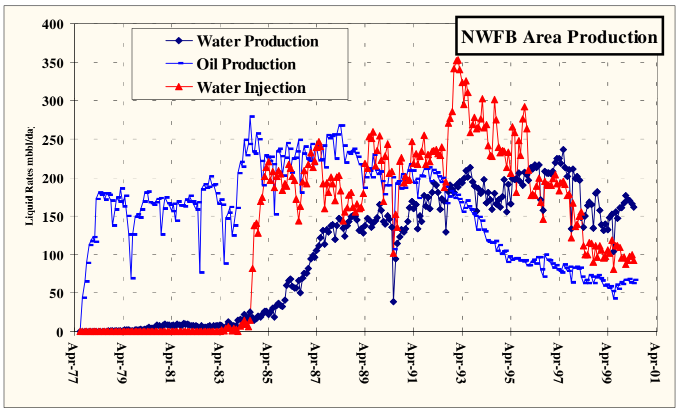
Figure 11: NWFB Oil Rate and Decline



Injection Targets using Frontsim Streamline Simulation

Injection well rates were set using the history matched Frontsim model (Ref. 6). Model dynamic allocations called for reducing the water injection rate from over 200 mbpd to 100 mbpd. This additional injection was not supporting production, yet technical evaluations had not identified or quantified the problem. The Frontsim simulation work was implemented in late 1997 early 1998 and the resultant water production immediately dropped 50-60 mbd. Multiple effects were taking place on the oil stream at the time, but the consensus is that oil rate has actually increased due to hydraulic effects and we are currently experiencing and incline in oil production. This demonstrated by the monthly production data in Figure 12.

Figure 12: Production Impacts in NWFB Waterflood



Reduced Water Cycling

Inefficient water injection is readily identified on a by well by layer basis in the simulation. The Frontsim model showed Well N-09 producing 100% water from Zone 3. A water shutoff was performed and 5000 bwpd eliminated without any oil loss. The simulation reduced uncertainty so that short term well work could be performed without impacting long term production.

Fluid Flux and Flood Front Management.

Managing flood front behavior has the potential to eliminate dead spots and reduce water cycling. Changing injector rates in the NWFB yielded immediate benefits and stopped flux into the GDWFI. Injection well work is likely to access more reserves. The benefits of profile modification, understanding fractured well performance, and impacts of taking injectors off line is also being implemented in the NWFB.

Conclusions

1. Injection well analysis and offtake management provided the most leveraging activity to increasing flood performance in the NWFB.
2. Integration of all types of tools and data provided a holistic reservoir analysis for the NWFB waterflood.
3. Integrated analysis pointed to necessary injection well work critical to remove inefficiencies and mitigate decline.
4. Streamline Flood Front Tracking Simulation provided an accurate means to manage the 3-D complexity of this mature multi-zone waterflood.

Acknowledgments

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